Section 4: Future Natural Gas Supply and Production

Both the National Petroleum Council (NPC) and Energy Information Administration (EIA) have recently concluded that while traditional North American producing areas will be able to supply about 75 percent of the nation's gas needs in 2020, additional supplies and production will be necessary to meet anticipated demand. The two additional gas resources that are likely to contribute significantly to North American natural gas supply in the longer term are liquefied natural gas (LNG) and Arctic (Alaska and Northern Canada) natural gas.[1] Another potential future resource is natural gas hydrates, which are sometimes referred to as methane hydrates. This resource although potentially tremendous in size is much more speculative and is only discussed briefly.

Arctic Natural Gas

The Arctic regions of Alaska and Northern Canada contain significant amounts of natural gas resources. These gas resources were discovered over 30 years ago, but because of high transportation costs they have not been developed. The trend towards higher gas prices, which began in 2000, has made the development of the Arctic resources much more attractive.

Alaska

The Minerals Management Service (MMS) of the U.S. Department of Interior in 2001 estimated the Alaska natural gas resource base at 220 Tcf, 88 percent of which is undiscovered.[2] Some of the gas resource will not prove to be economically viable, residing in small fields, or in regions too remote for extraction. Most of the proven economical reserves are located onshore and offshore in Northern Alaska. A small amount is located in Southern Alaska at Cook Inlet where it is used for local consumption and as feedstock for a small LNG terminal were gas is sent to Yokohama, Japan. Some natural gas is consumed each year by the petroleum industry, but 85 percent of the gas that is extracted is re-injected into the oil fields to maintain pressure, and for future use.

The undiscovered gas resources are much larger (192 Tcf) than the discovered reserves, and are equivalent to roughly 40 percent of the estimated undiscovered conventional reserves in the Lower 48. Over time the assessment of the Alaska gas resource is likely to increase as the lack of a local market or export potential have limited exploration and geological surveying in Alaska. However, since the undiscovered resources are just that, undiscovered, estimating what fraction is economically recoverable is difficult. The MMS estimated that at $2/MMBtu only 6.2 Tcf of undiscovered natural gas is economically recoverable. The economically recoverable volumes increase to 12.2 Tcf and 35.8 Tcf at market prices of $3.35/MMBtu and $5.80/MMBtu respectively. At the higher natural gas prices experienced during 2003 and 2004 it is reasonable to assume that the current economically recoverable natural gas resource (proved reserves and potential resources) in Alaska ranges from 50 to 60 Tcf. Over time, technological improvements and continued

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[1] Natural gas resources in Mexico are not well assessed and could potentially contribute significantly to North American supply.

[2] The NPC 2003 estimates the Alaska technical resource base at 331 Tcf using advanced technology.

exploration will most likely increase the economically viable Alaska gas resource and production potential.

Transport Options for Alaska Natural Gas

At this time Alaska natural gas is essentially stranded and will require a pipeline, physical conversion to LNG, or chemical conversion to some other type of liquid hydrocarbon in order to reach markets in the continental United States. The two likely pipeline options for accessing Alaska natural gas are discussed briefly below.

1. The most direct route is to build a line from Prudhoe Bay to the Mackenzie Delta project that is being developed by the Canadians. This would give the Alaska natural gas access to existing northern Alberta pipelines. Estimated cost is 10 to 15 billion dollars, and would require gas prices above $3.5/MMBtu (MMS, 2001).
2. The alternative route, and the one favored by Alaskan politicians, would parallel the existing oil pipeline to Fairbanks, and then follow the Alaska highway towards Valdez, before heading southeast to the gas pipelines in northern British Columbia. Estimated cost is 17-20 billion dollars, and would require long-term gas prices above $3.75/MMBtu (MMS, 2001).

Other options such as LNG liquefaction at a Southern Alaska port, or gas to liquid (GTL) transformation followed by transport on the oil pipeline has been considered but is currently too expensive. British Petroleum is currently experimenting with a small GTL unit on the North Slope.

While there have been several false alarms about Alaska natural gas becoming marketable it seems likely that federal support in the form of loan guarantees or price supports will result in one of the pipeline options being actively pursued within the next year. Alaska natural gas probably won't enter the market until 2013-15, but eventually would contribute 5 Bcf/day, or nearly 2 Tcf/year (8 percent), to North American supply.

Because of Washington State's proximity to Alaska and the gas pipeline systems in British Columbia and Alberta we can anticipate several benefits from development of Arctic natural gas resources. First, this ensures that a long-term supply of natural gas will be delivered to the regional pipeline system. In addition, construction and operation of the pipeline will require material and labor some of which will be supplied by Washington State. Finally, the project will require use of Washington State ports for transport of materials and personnel.

Northern Canada

Proven gas reserves in the Mackenzie Delta/Beaufort Sea area of Northern Canada are estimated at 9 Tcf. The potential resource is estimated at 55 Tcf, resulting in a total resource base of 64 Tcf (CERI, 2003). The pipeline required to develop the Mackenzie resource is currently in the planning stages and is expected to come into service by 2008-09 with an initial annual production volume of 0.6 Tcf (1.5 Bcf/day), expandable to 0.8 Tcf. Cost for the pipeline is estimated at 2 to 3 billion dollars.

The Mackenzie gas resource may not be a significant contributor to the North American gas supply because of the continued development of the Alberta oil sands.[3] A large amount of energy is required to extract and process the bitumen from the sand: 1 Mcf natural gas per 1.2 barrels of bitumen processed or 0.5 Tcf of gas per year for projected 2010 oil sands production (First Facts, 2003). In addition, natural gas liquids and light naphtha from conventional oil are required to further upgrade the bitumen into a synthetic crude that can be processed by Canadian or U.S. refineries.

Liquefied Natural Gas Imports

Meeting future U.S. natural gas demand will require not only aggressive development of new conventional, unconventional (coal-bed methane, tight sands, etc) and frontier gas resources in the United States and Canada, but also the rapid expansion of another gas source – imported LNG. In the spring of 2003, LNG made the headlines after Federal Reserve Chairman Alan Greenspan presented the fed's view to Congress on recent turmoil in the U.S. natural gas market, and the need for new gas supplies. Chairman Greenspan identified LNG as the most promising new source of natural gas, and anticipated that it would eventually be freely traded like petroleum, which would serve to dampen price volatility in the U.S. market.

LNG is one of the world's most rapidly growing fuels, accounting for 21 percent of all gas imports and exports (5.1 Tcf), and serving nearly 6 percent of worldwide natural gas demand in 2001 (PGC, 2002). LNG growth has averaged 6.4 percent per year over the last 20 years with most of the expansions being made in Asia. Energy analysts believe that in the next decade LNG will be freely traded like petroleum, and that daily spot market prices will be prominently listed.

In the United States, LNG is emerging as an important supplemental resource to meet growing U.S. natural gas demand. Worldwide proven reserves of natural gas were 6,076 Tcf in 2002 (EIA, 2004), and the total potential gas resource was estimated at over 13,000 Tcf. By comparison, in 2002 U.S. proven reserves were estimated at 188 Tcf (EIA, 2003) and Canadian reserves at 60 Tcf. World reserves are many times larger than North American reserves, but are often stranded far from market, in countries that have limited current or future need for the natural gas.

LNG process

The key components of the LNG process are: 1. Liquefaction; 2. Shipping; and 3. Regasification.

The first step is liquefaction where feedstock from the production gas field is taken to the liquefaction plant, where contaminants such as water, carbon dioxide and nitrogen are removed. The cleaned natural gas is cooled using large refrigeration units (called trains) until the gas liquefies at a temperature of –256 °F. The liquefaction process reduces the volume of the natural gas by a factor of 600, resulting in a product (LNG) that can be economically transported by ship.

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[3] The Canadian National Energy Board in its *Energy Market Assessment 2004*, estimated that synthetic crude oil production from the oil sands will slightly more than double between 2003 and 2015.

The next step involves loading the LNG onto a special tanker, which has several insulated double hulled stainless steel tanks that contain the super cooled LNG at atmospheric pressure. The tankers cost approximately $160 million, and can carry 2.6 to 2.8 Bcf of LNG (Institute for Energy, 2003). A small amount of LNG must be boiled off to keep the bulk of the LNG in its liquid form, and is used as fuel for the tanker's propulsion turbines. As of December 2002, there were 136 LNG tankers with 57 ordered for delivery by 2006.

The final step is converting the LNG back to a gas at a regasification facility. The LNG is pumped out of the tanker into a land based cryogenic container, then sent through several expansion chambers as it is warmed and converted into a gas. The natural gas is then either stored or enters a natural gas pipe system for delivery to customers.

LNG economics

Experience and economies of scale gained from the development of the East Asian LNG market have driven down LNG production costs in nominal terms by 30 to 40 percent over the last decade (Utilis, 2003). Gas liquefaction costs dropped from an average of $560/ton during 1986-1990, to $250/ton 1996-2000, while LNG vessel costs have dropped from $230 million to $160 million. Table 4.1 illustrates the improving economics of LNG.

Table 4.1: LNG component costs in 1995 and 2002

Cost component	Year: 1995 ($/MMBtu)	Year: 2002 ($/MMBtu)
Netbacks *	0.50	0.75
Pipelines	1.00	0.75
Liquefaction plant	1.25	1.00
Shipping	1.25	0.65
Gasification	0.35	0.35
Delivered to Market	4.35	3.50

Source: *Introduction to LNG*, Institute for Energy, Law & Enterprise, Jan. 2003.

*Netbacks are the return for the gas resource project developer.

Concerns over facility siting, regulations, and security within the United States may add slightly to the delivered gas costs shown above. In addition, West Coast costs will be somewhat higher due to longer transportation distances. Table 4.2 presents the NPC's estimates of long-term market prices, by location, at which LNG will becomes economically viable. With current technology, LNG imports should be viable when long-term Henry Hub natural gas prices exceed $3.25 to $4.0/MMBtu. LNG import costs are significantly lower at the four existing U.S. LNG facilities relative to estimated costs for new LNG regasification facilities. On the U.S. West Coast a long-term gas price in excess of roughly $4.5/MMBtu, would be necessary because the LNG must be transported significantly greater distances.[4] See Appendix B for estimated transportation costs from different producing regions. Over the long-term, the price at which LNG

[4] West Coast LNG would come either from Qatar, Indonesia, Australia, or possibly Bolivia. The latter would require an extensive pipeline to transport the gas to a Chilean port.

becomes economical will probably decrease slightly as production, liquefaction, transportation, and regasification economics continue to improve.

Table 4.2: Price at which LNG becomes economically viable

Facility Location	Trigger price (2001 $/MMBtu)
Everett, MA	3.42
Cove Point, MD	3.33
Elba Is., GA	3.23
Lake Charles, LA	3.41
New England	4.02
Florida	3.96
Washington/Oregon	4.53
California	4.26
Baja California, Mexico	3.32

Source: NPC 2003

LNG Safety

LNG has been handled safely for years. There are currently 12 countries with 17 liquefaction facilities that produce LNG (NPC, 2003). See Figures 4.1 and 4.2 on the next page for locations of existing and proposed liquefaction facilities. Over the life of the industry there have been eight marine accidents worldwide, but no fires, or catastrophic explosions, or shipboard fatalities. Isolated accidents and fatalities have occurred at terminals, most in the early days of the industry. The recent explosion at the Skikda natural gas liquefaction facility in Algeria will undoubtedly bring the safety issue to the forefront again. The Federal Energy Regulatory Commission (FERC) is currently evaluating LNG safety.

In the United States, one commercial LNG facility failed in operation, and caused catastrophic damage to Cleveland, Ohio, in 1944.[5] A shortage of high quality stainless steel during World War II led to compromises in LNG storage tank design, and consequently a storage tank failed and filled the streets and storm sewers of adjacent neighborhoods with natural gas. The vaporized LNG ignited and 128 people subsequently died. No cracks have been reported in the past 35 years with more modern tank designs. However, since that time, LNG facilities have been generally limited to more remote locations. There have been no catastrophic accidents in the United States involving LNG storage tanks since 1944. Industrial accidents, including fatalities, occurred at U.S. LNG facilities in 1973 and 1979, but were much more limit in damage and did not involve catastrophic tank failures. These accidents resulted in several design changes that have since been implemented industry wide (Institute for Energy, 2003).

The terrorist attacks of September 11, 2001, raised concerns about security risks at LNG facilities, particularly those located near large urban centers. Additional security measures will likely be necessary to minimize the potential terrorist threat at these sites.

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[5] From the *Encyclopedia of Cleveland History*, Case Western Reserve University: *The EAST OHIO GAS CO. EXPLOSION AND FIRE took place on Friday, 20 Oct. 1944, when a tank containing liquid natural gas equivalent to 90 million cubic feet exploded, setting off the most disastrous fire in Cleveland's history*

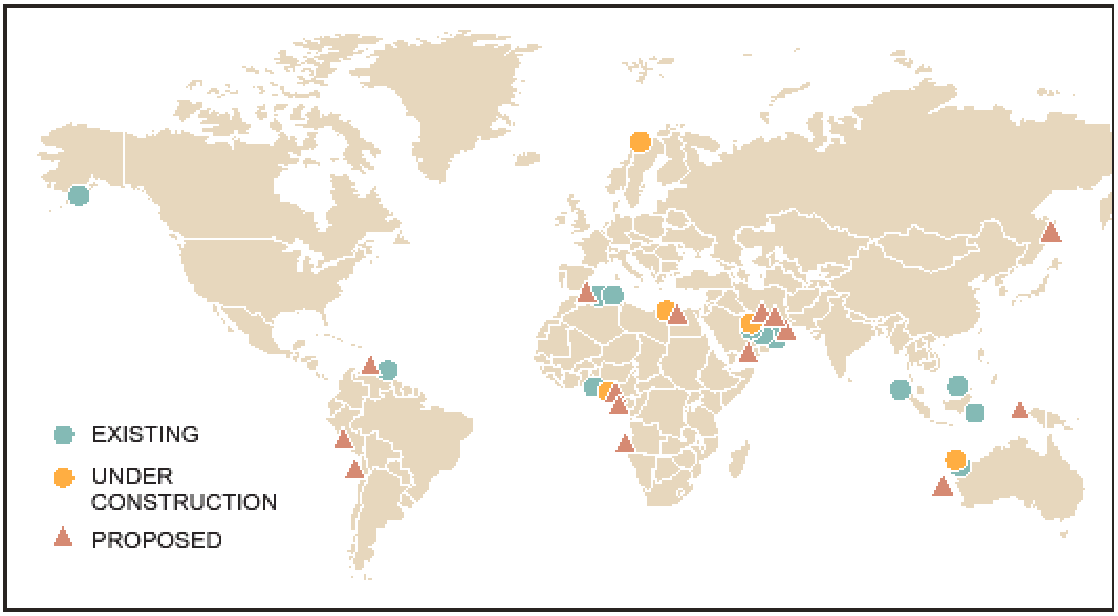

Figure 4.1: Existing and proposed LNG liquefaction facilities worldwide
Source: NPC, 2003

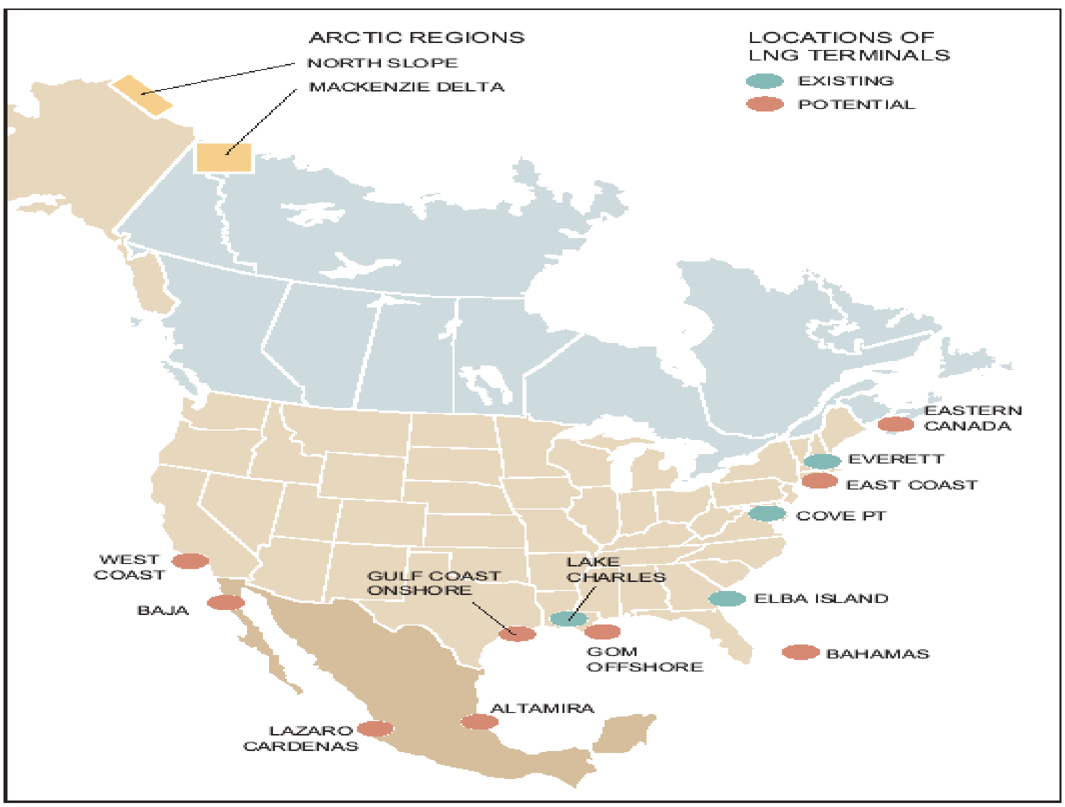

Figure 4.2: Existing and proposed LNG receiving terminals in North America
Source: NPC, 2003

LNG Facilities

The United States currently has four LNG receiving terminals located on the East and Gulf coasts. These terminals were designed and constructed in the late 1970s when regulated wellhead gas prices and a series of oil crises caused natural gas demand to exceed supply. Natural gas prices collapsed during 1983-85 as wellhead price deregulation continued and oil prices began to slide. Three of the four LNG terminals were mothballed and the fourth operated at minimal capacity during the 1980s and '90s. Following the run-up in natural gas prices in 2000-01, efforts were undertaken to reactivate and upgrade the terminals. The capacities and expansion plans for the existing LNG terminals are shown in Table 4.3 below.

Table 4.3: Current U.S. LNG facilities

Location	Capacity (MMcfd)	Storage capacity (Bcf)	Expansion plans (MMcfd) (Bcf)	Owner or operator
Everett, MA	435	5.5	600, ---	Distrigas
Elba Is., GA	440	6.4	360, 3.3 storage	Southern
Lake Charles, LA	630	10.1	590, 2.5 storage	CMS
Cove Pt., MD	1,200	8.5	---, 2.8 storage	Dominion

Maximum LNG delivery capacity is currently about 2.7 Bcf/day and with expansions will rise to 4.2 Bcf/day by 2007-08. Assuming a 75 percent capacity factor this could translate to deliveries of 2.0 Bcf/day with current capacity and 3.2 Bcf/day following the proposed expansions: Representing about 3 and 5 percent respectively of current average daily U.S. gas consumption. Limitations on the supply and transport components of LNG delivery will probably constrain market share development for several years. Over the long-term, LNG market share is anticipated to grow significantly: Utilis Energy forecasts more than 5 percent market share by 2008, while Cambridge Energy Research Associates (CERA) forecasts LNG taking 10 to 20 percent of the market by 2020.

Numerous sites in the United States, Canada, Mexico and the Bahamas are being considered for LNG import facilities. No LNG site development is being actively pursued in the Northwest. Siting in the United States may be particularly difficult due to state and federal regulatory restrictions and local opposition. For this reason, sites in Mexico and the Bahamas that can serve the U.S. market are also being considered. Offshore LNG degasification terminals are less controversial and are also being studied.

Considering the significant cost of developing LNG liquefaction or regasification facilities, project financing will be of major concern, and consequently most development work is being undertaken by the large international energy companies and their national energy company counterparts. These organizations have the personnel, experience and resources to pursue risky, but potentially highly profitable projects.

More than two dozen LNG projects have been proposed for North America over the last several years: See Appendix B for a current list. While many of the proposed projects are speculative and unlikely to be completed, several projects are likely to be completed as they are backed by major oil and gas companies and have advanced through the early permitting process. The major oil companies have an additional advantage in that all of them are involved in the other steps of the LNG development chain – remote natural gas field development and planning and construction of gas liquefaction facilities. For North America as a whole over the next decade, a reasonable conjecture is that two to four LNG facilities will be constructed on the Atlantic and Gulf coasts, and two to three on the Pacific Coast (Natural Gas Weekly, 2003). Combined with the four existing U.S. LNG facilities, the potential LNG contribution to the North American gas market is slightly more than 3 Tcf /year, or roughly 10 percent of anticipated demand.

In 2003, Cherry Point Energy LLC announced a proposal to develop a LNG facility in the Puget Sound region. The proposed facility is of modest size, 450-500 million cubic feet (MMcf)/day, and could in theory supply about 15 percent of natural gas needs in the Pacific Northwest (Forbes, 2004). Several utilities have expressed interest in the project. A facility site has not been selected yet.

A number of factors will influence the rate at which LNG gains market share in the United States. Some of these factors are listed below.

- Long-term perceived price of natural gas. Periods of low gas prices, as seen in 2002, will make LNG projects appear more risky to developers.[6]
- Lack of sufficient liquefaction facilities, transportation and regasification facilities and supporting infrastructure. For LNG to competitively enter the U.S. market the expensive and complicated steps described in the sections above must be completed concurrently.
- Overcoming the Not In My Back Yard (NIMBY) reaction. Local opposition to LNG regasification terminals will be significant and may delay or stop many proposed projects. Remote, offshore and industrial locations will have significant siting advantages
- Safety concerns will shape public opinion and project permitting,
- Balance of trade concerns. The United States currently runs a large trade deficit – importing significant quantities of LNG would add to the deficit.

LNG Contracting

Historically LNG contracting has been conducted on a long-term basis, with many contracts running 15 to 20 years. In the United States, the natural gas market has since deregulation evolved into a short-term market, with most purchases being made on the daily or monthly spot market. The differences in these two markets may present some difficulties for LNG market development. However, the LNG spot market does seem to be developing with 8 percent of traded LNG being purchased on the short-term market in 2002 (EIA, 2004). In addition to hedge against market volatility there is a trend in the U.S. gas market back to longer term contracts, which is a better match for the capital intensive LNG industry.

[6] Developers will require a risk premium, adding to the internal rate of return necessary to make projects viable.

Natural Gas Hydrates

Natural gas hydrates are solid, crystalline, ice-like substances composed of water, natural gas and other gases, and are formed at moderate pressure and reduced temperatures. The natural gas is trapped in the lattice like structure of the frozen water, and is released when the hydrate is warmed. Gas hydrates are found in permafrost regions and in ocean sediments at depths greater than 450 meters. The gas hydrate resource is immense, dwarfing all other hydrocarbon resources, with a central potential resource estimate of 742,000 Tcf. For comparison, the global potential resource of conventional natural gas is estimated at only 13,000 Tcf. The Alaska gas hydrate resource is estimated at 169,000 Tcf, with over 99 percent located in offshore regions.

Although gas hydrates are a vast potential resource, none are being commercially processed into natural gas. Japan and the United States have committed significant research money to developing the technology to commercially exploit the gas hydrate resource. The large-scale commercial extraction of natural gas from gas hydrates is not expected for at least 20 years.

Summary

Our review of the recent natural gas production statistics and forecasts prepared by the NPC, EIA, AEUB and various industry analysts allows us to make the following observations.

1. Artic natural gas has great production potential, (Alaska 5 Bcf/day, Northern Canada 1.5 Bcf/day), but is an expensive and risky resource to develop.
2. Development of the Arctic resources will take 10 to 20 years.
3. LNG is currently cost competitive in many parts of the United States, and has the potential to enter the gas market in limited amounts at four existing LNG receiving facilities.
4. By 2008, it is likely that capacity upgrades at the four existing LNG receiving facilities will be complete and in addition several new facilities will become operational, making additional LNG imports possible.
5. LNG trigger prices are slightly higher for the West Coast of North America.
6. The EIA forecasts that the United States will import 4.1 Tcf per year of LNG by 2020, representing nearly 14 percent of U.S. gas supply. In 2003, the National Petroleum Council forecast a 15 percent market share for LNG by 2020. A recent report by Cambridge Energy Research Associates (CERA) forecasts that LNG will take a 10 to 20 percent market share by 2020.
7. Over the next 5 years LNG imports will have a limited impact on North American natural gas prices. Ten or more years in the future LNG will have a more pronounced effect on gas prices and may prevent the development of marginal gas fields within the United States and Canada.[7]

[7] Energy analysts have speculated that development of an extensive LNG market in the U.S. will result in the long-term decline of the domestic natural gas exploration and production industry.